

Editor's note: appealed -- Civ.No. 92-99-BLG (D.MT May 28, 1992), IBLA decision vacated as to compression costs, remanded to IBLA (Sept. 22, 1993)

BEARTOOTH OIL AND GAS CO.

IBLA 90-304 Decided March 3, 1992

Appeal from a decision of the Director, Minerals Management Service, upholding an order of the Denver Royalty Compliance Division assessing additional royalties. MMS-89-0117-O&G.

Affirmed.

1. Oil and Gas Leases: Royalties: Generally--Federal Oil and Gas Royalty Management Act of 1982: Royalties--Words and Phrases

"Marketable condition rule." A Federal oil and gas lessee is under an obligation to assume the expenses of placing any gas produced and sold into "marketable condition." No deduction from royalty is allowed for the expenses of compressing gas required to place it in marketable condition regardless of whether these costs are paid directly by the lessee or by a third party. The price of gas sold at the wellhead which has been reduced from the price of gas in marketable condition by the costs of compressing it as required for marketing to a pipeline purchaser does not establish the value of the gas in marketable condition.

APPEARANCES: Gary G. Broeder, Esq., Billings, Montana, for appellant; Howard W. Chalker, Esq., Office of the Solicitor, U.S. Department of the Interior, Washington, D.C., for the Director, Minerals Management Service.

OPINION BY ADMINISTRATIVE JUDGE GRANT

Beartooth Oil and Gas Company has appealed from a decision of the Director, Minerals Management Service (MMS), dated February 5, 1990, upholding an order of the Denver Royalty Compliance Division, MMS, assessing additional royalties. The latter order, dated February 23, 1989, held that appellant had underpaid royalties in the amount of \$32,107.25 on gas produced and sold from 10 Federal oil and gas leases during the period January 1980 through December 1986. ^{1/} This underpayment occurred, MMS found, because Beartooth improperly deducted compression charges when calculating and paying royalties due.

^{1/} These leases are: SL-071172, U-026, U-24632, U-25888, U-29334, U-30301, U-31272, U-41378, U-44444, and U-51052.

The MMS order was based in part upon language in Notice to Lessees (NTL) Nos. 1 and 5 to the effect that no deduction will be allowed for the cost of gathering and compressing gas which an operator incurs by reason of placing the gas in a marketable condition, as an operator is obligated to do so at no cost to the lessor. See NTL-1, 42 FR 4546, 4548 (Jan. 25, 1977); NTL-5, 42 FR 22610, 22611 (May 4, 1977). 2/

Two separate elements of compression costs are at issue here. The first question involves compression costs occurring downstream of the leasehold. Beartooth produced natural gas from its Federal leases and sold it to Mesa Pipeline Company under a gas purchase agreement. The gas was sold at the meter connection on each of the respective Beartooth leases and title to the gas was transferred at that point. Downstream of the point of sale from Beartooth, Mesa compressed the gas as required to make delivery to its purchaser, Mountain Fuel Resources, Inc. Pursuant to its agreement with Beartooth, Mesa reduced the price which it paid to Beartooth by the amount of the downstream compression costs incurred in order to market the gas to Mountain Fuel. MMS found that underreporting occurred when Beartooth then computed the royalty due on its production by applying the royalty rate to the net sales price paid by Mesa after deducting compression costs. 3/ A secondary question involves the deduction of charges incurred by Beartooth for the use of a compressor at its Bryson Canyon #17 well.

The Director's decision of February 5, 1990, which upheld the order of the Denver Royalty Compliance Division, relied in part on regulation 43 CFR 3162.7-1(a). This rule provides: "The operator shall put into marketable condition, if economically feasible, all oil, other hydrocarbons, gas, and sulphur produced from the leased land." The Director noted that it is well established that the operator of Federal leases is obligated to market production from the leases without deduction of compression costs, citing the Geological Survey Conservation Division 4/ Manual, which states at section 647.2.3A: "The lessee is obligated to place lease production in marketable condition without deduction of costs for measuring, compressing, or otherwise conditioning the gas for market."

In his February 5, 1990, decision, the Director responded to Beartooth's argument that Mesa's downstream compression was unnecessary for

2/ NTL-1 and NTL-5 have been superseded and terminated effective Mar. 1, 1988. 30 CFR 206.150(e); 53 FR 1230, 1271 (Jan. 15, 1988).

3/ In affirming the order to pay additional royalties, the Director upheld the findings of the State of Utah Tax Commission, which audited Beartooth's royalty payments under authority delegated pursuant to section 205 of the Federal Oil and Gas Royalty Management Act, 30 U.S.C. § 1735 (1988).

4/ Prior to creation of MMS, royalty collection was the responsibility of the Conservation Division of Geological Survey. MMS was created by Secretarial Order No. 3071 (Jan. 19, 1982). 47 FR 4751 (Feb. 2, 1982). Matters relating to royalty and mineral revenue management were subsequently transferred to MMS under Secretarial Order No. 3087 (Dec. 3, 1982). 48 FR 8983 (Mar. 2, 1983).

Beartooth to satisfy its duty to market production. The Director found this argument to be without merit because "the compression performed by Mesa is not an event that occurs independently of Beartooth's sale of the gas to Mesa." In support of this conclusion, the Director looked to the price paid by Mesa to Beartooth and found that it had been "calculated by a formula which includes a reduction for the downstream compression costs incurred by Mesa in its sale to Mountain Fuel." 5/

Appellant's sales contract expressly provides for a deduction from the sales price to compensate Mesa for the costs of compression, the Director found, and the proceeds received by Beartooth upon sale are directly diminished by these costs. Even if the marketing costs in dispute are Mesa's and not appellant's, it is clear that Mesa has passed those costs on to appellant in the form of a deduction from the gas sales price, the Director stated. The fact that a lessee, in effect, pays the purchaser to compress the gas by accepting a reduction in the sales price does not alter the rule that the lessee cannot reduce the royalty value by the cost of compressing the gas (Director's Decision at 3-4).

In its statement of reasons (SOR) for appeal to the Board (dated April 5, 1990), Beartooth emphasizes that its sale of gas to Mesa is an arm's-length transaction. Title to the gas is transferred from Beartooth to Mesa at the meter connection on the subject leases (SOR, Apr. 5, 1990, at 1). The price paid to Beartooth is the Mesa-Mountain Fuel price less Mesa's compression charges (SOR on appeal to the Director, dated Apr. 27, 1989, at 3). Appellant states that Mesa's resale of this gas to Mountain Fuel is similarly an arm's-length transaction. Beartooth, Mesa, and Mountain Fuel are unrelated entities, appellant urges, and Beartooth in no way controls or is involved with Mesa's resale to Mountain Fuel.

No compression is required for Beartooth to either sell or make delivery of its gas to Mesa, appellant states. Mesa, however, performs two stages of compression to allow it to make deliveries to Mountain Fuel (SOR, Apr. 5, 1990, at 1, 2). Compression occurs offlease and downstream of the Beartooth-Mesa meter while the gas is under Mesa's exclusive control, appellant remarks. Appellant argues that these facts distinguish the present appeal from California Co. v. Udall, 296 F.2d 384 (D.C. Cir. 1961), where compression was performed on the leasehold by the operator prior to sale. Beartooth is in no manner performing the compression here, appellant states, nor is it being compensated or reimbursed for such services.

Beartooth further argues that even assuming the Director is correct that a lessee is obligated to place lease production in marketable condition without a deduction for compression costs, this principle is misapplied here. Beartooth's market for the gas is Mesa, appellant urges, and no compression is required for Beartooth to sell to Mesa. Compression is, therefore, unnecessary to place the gas in marketable condition insofar as the Beartooth-Mesa market is concerned (SOR, Apr. 5, 1990, at 2).

5/ Director's decision at 3, quoting from Mesa's brief before the Director, dated Apr. 27, 1989, at 1.

Appellant acknowledges that the Beartooth-Mesa price is determined by a formula which includes, inter alia, a reduction for compression costs incurred by Mesa, but explains this fact by noting that Mesa must determine the wellhead price it can afford to pay producers like Beartooth by deducting its marketing costs and profit margin from the resale price it receives from Mountain Fuel. If it failed to do so, it would soon be out of business, appellant argues.

[1] It is well established that a Federal oil and gas lessee is under an obligation to assume the expenses of marketing any gas produced from the leasehold. The Texas Co., 64 I.D. 76, 79 (1957). ^{6/} In that case the lessee operated only two wells in a much larger field and contracted with Humble Oil, the operator of gathering pipelines and compressor stations, to transport the low-pressure gas from appellant's separator at the wellhead to the point of market at the pipeline and to compress the gas to the pressure required for entry into the buyer's pipeline. The lessee argued that it was not economically feasible for it, as the operator of only two wells in the field, to install equipment to gather and compress the small amount of gas produced from its wells. Hence, the lessee sought to deduct the costs charged by Humble for gathering and compressing the gas. The Department explicitly rejected appellant's contention that lessee's duty was limited to marketing the low-pressure gas at the wellhead thus entitling the lessee to deduct the cost of transporting the gas to the point of market in the field and placing the gas in such condition that it can enter that market:

The lease requires the lessee to market the production from the lease and until the gas from the wells is in such a condition that it can be sold in the market, it cannot be said that the lessee has fulfilled his obligations under the lease. The lessee has not shown that the gas can be marketed at the pressure with which it comes from the wells.

The Texas Co., 64 I.D. at 79.

We find this precedent to be controlling in the present case. Appellant would seek to distinguish the facts of The Texas Co. case and the present appeal in that the lessee in the former contracted with a third party to undertake gathering and compression of the gas for the market whereas, in the present appeal, the lessee sold the low-pressure gas to the party undertaking the gathering and compression for a price reduced from the market price by the amount of the costs of gathering and

^{6/} The duty of the Federal lessee to market the gas was held to be clearly spelled out in the regulation at 30 CFR 221.35 (1959) requiring the lessee to avoid waste of gas and to either market it, consume it beneficially, or return it to the producing formation. 64 I.D. at 79. A similar requirement is found in the operating regulations currently in effect which mandate that: "The operator shall put into marketable condition, if economically feasible, all oil, other hydrocarbons, gas, and sulphur produced from the leased land." 43 CFR 3162.7-1(a).

compression. We find this distinction to be immaterial. Whether the lessee assumes the expense of gathering and compression himself or pays a third party to perform this function for him, the cost is an obligation of the Federal lessee. Further, it makes no difference whether the lessee transfers title to the gas at the wellhead meter for a price reflecting a reduction from the market price by the amount of the gathering and compression costs or whether the lessee retains title and pays a contractor to undertake this function. Case law clearly establishes that Beartooth's sale of gas to Mesa does not compel a finding that the gas was in market-able condition at the time of sale. Big Piney Oil & Gas Co., A-29895 (July 27, 1964) (compression and gathering costs incurred after sale of gas to operator of gathering system were not deductible); Placid Oil Co., 70 I.D. 438 (1963) (transfer of title did not alter nondeductibility of certain expenses incurred thereafter); cf. Arco Oil & Gas Co., 109 IBLA 34 (1989) (the point of first "sale" is generally an indication of the existence of a market, but the transfer of title to oil at an offshore platform may not establish a market at that point where the oil was subsequently transported to market by pipeline and held for the account of the producer).

The principles set forth in The Texas Co. case have been upheld by the courts. In California Co. v. Udall, *supra*, the operator of a Federal oil and gas lease produced gas that it sold for 12 cents per thousand cubic feet (mcf). The contract of sale called for gas produced from the wells conditioned as necessary to meet certain specifications required to make the gas suitable for pipeline transmission. Maximum water content and liquefiable hydrocarbons were specified in the contract, and the parties further provided that the gas would be delivered at pipeline pressure.

California Company, the operator, spent 5.05 cents per mcf in making the gas suitable for pipeline transmission and paid royalty upon the difference between its sale proceeds (12 cents per mcf) and its production costs (5.05 cents per mcf). ^{7/} The Secretary disagreed and billed California Company for royalties based upon 12 cents per mcf. The court held that section 17 of the Mineral Leasing Act, 30 U.S.C. § 226(c) (1988), required a Federal lessee to pay a royalty of 12-1/2 percent on the value of production. 296 F.2d at 386-87.

The Court of Appeals for the District of Columbia Circuit found that California Company was required by regulation to market the gas removed from its leasehold. Because of this duty to market (and not merely sell) the gas, the court held that the Secretary could reasonably construe the statutory term "production" to mean gas conditioned for market. Gas conditioned for market was gas that satisfied market specifications for water content, liquefiable hydrocarbons, and compression, such as those set

^{7/} California Co. v. Seaton, 187 F. Supp. 445, 447 (D.D.C. 1960), sets forth in detail the calculation used by California Company in valuing production at 6.95 cents per mcf (12 cents per mcf less 5.05 cents per mcf).

forth in the sales contract of California Company. 296 F.2d at 388. The Secretary's valuation of production at 12 cents per mcf was, accordingly, affirmed.

Key to the relevance of the Circuit Court's holding in resolving Beartooth's appeal is the following paragraph from the court's opinion:

The premise for the Secretary's decision in the case before us was that, since the lessee was obliged to market the product, he was obligated to put it in marketable condition; and that the "production" was the product in marketable condition. Theoretically, any gas--any "production" --is "marketable". We can assume that, if the price were low enough to justify capital expenditures for conditioning equipment, someone would undertake to buy low pressure gas having a high water and hydrocarbon content. A lessee who sold unconditioned gas at such a price would, in a rhetorical sense, be fulfilling his obligation to "market" the gas, and by thus saving on overhead he might find such business profitable. There is a clear difference between "marketing" and merely selling. For the former there must be a market, an established demand for an identified product. We suppose almost anything can be sold, if the price is no consideration. In the record before us there is no evidence of a market for the gas in the condition it comes from the wells. The only market, as far as this record shows, was for this gas at certain pressure and certain minimum water and hydrocarbon content. [Footnote omitted.]

296 F.2d at 387-88. Although the appellant seeks to distinguish the present case on the basis that the gas was marketed near the wellhead, we find that this does not constitute marketing of the gas. Regardless of the fact the gas could be sold at this point to the operator of the field gathering system and the compressor plant necessary to introduce the gas into a pipeline (other than a low-pressure gathering system pipeline), we cannot uphold this effort to place the cost of production of gas in "marketable condition" on the lessor. Although we think it is clear from the above-quoted discussion that the court in California Co. distinguished this

type of "sale" from "marketing" of gas production, it is also evident from cases such as Big Piney Oil & Gas Co., *supra*, and Placid Oil Co., *supra*, that deductions from market value for costs of gathering and compression necessary to market the gas are not allowable even where incurred after transfer of title from the lessee. Recent litigation has confirmed that the "Marketable Condition Rule" requires valuation of gas production without deduction of the costs of gathering and compressing the gas necessary to place the gas in marketable condition. Mesa Operating Ltd. v. U.S. Department of the Interior, 931 F.2d 318, 325 (5th Cir. 1991); *see Shoshone Indian Tribe v. Hodel*, 903 F.2d 784 (10th Cir. 1990).

A second issue regarding compression costs is also present in this appeal. In his February 5, 1990, decision, the Director found that Beartooth had improperly deducted from gross proceeds a rental charge that

Beartooth itself had incurred for a compressor used on its Bryson Canyon #17 well. The Director held that such a deduction was improper because gas production should be valued at market price without a deduction for compression costs. In its SOR, Beartooth notes that it was required for a period of time to rent a compressor on its Bryson Canyon # 17 well in order to meet the Mesa line pressure. Mesa's line pressure was prohibiting this well from producing. Absent this compression, Beartooth states, no gas could have been produced from this well and the United States would have received no royalty.

Beartooth argues that the Director's decision violates 30 CFR 206.103 (1987), which requires MMS to give due consideration to the price received by the lessee and "other relevant matters." The Director's position ignores the "other relevant matters" criteria, appellant states, and is inconsistent with commonly accepted industry practice. As an example of this industry practice, appellant cites Piney Woods School v. Shell Oil Co., 539 F. Supp. 957 (S.D. Miss. 1982), for the proposition that a lessor should share in the costs incurred by the lessee in processing and transporting gas in fulfillment of its marketing responsibilities. Further, appellant cites Parker v. TXO Production Corp., 716 S.W.2d 644, 648 (Tex. Ct. App. 1986), in support of its contention that the compression charges should be allowed as a deduction against royalty valuation. 8/

In response to appellant's argument, counsel for MMS correctly points out that NTL-5 was a duly promulgated rule of the Department at all relevant times. 9/ This rule provided in pertinent part: "[N]o deductions will be allowed for the uncompensated cost of placing the gas into marketable condition." 42 FR at 22611.

8/ Appellant cites, in particular, the following language from the decision:

"The crucial question is whether TXO's compression was a 'production cost' or a 'marketing cost.' Production costs are the expenses incurred in exploring for mineral substances and in bringing them to the surface. Absent an express term to the contrary in the lease, these costs are not chargeable to the non-operating royalty interest. Costs incurred after production of the gas or minerals are normally proportionately borne by both the operator and the royalty interest owners. See 3 H. Williams & C. Meyers, The Law of Oil & Gas § 645.2 (1985). These 'subsequent to production' costs include the expenses of compressing gas to make it deliverable into a purchaser's pipeline."

Parker v. TXO Production Corp., 716 S.W.2d at 648.

9/ In support, counsel writes:

"In 1987, when Congress enacted the Notice to Lessees Numbered 5 Gas Royalty Act of 1987, Pub. L. No. 100-234, 101 Stat. 1719 (1988), it expressly found that 'NTL-5 was a duly promulgated rule of the Department of the Interior within the meaning of the Administrative Procedure Act.' Id. at section 1(b)(2)" (Answer, Aug. 8, 1990, at 4). See also 43 CFR 3162.1(a) requiring an operator to comply with all NTL's. This regulation was effective Nov. 26, 1982.

It is clear from the record that the rental charges for the Bryson Canyon #17 well compressor were incurred to place appellant's gas in marketable condition. The compressor, as noted above, enabled Beartooth to move its gas from the Bryson Canyon #17 well into the pipeline. Under the provisions of NTL-5 the Board cannot allow a deduction of these charges. Cases such as those cited by appellant involving application of state law to production from non-Federal leases do not support a different result in this case involving valuation of production from Federal leases. Mesa Operating Ltd. v. U.S. Department of the Interior, supra at 325 n.48. 10/

Therefore, pursuant to the authority delegated to the Board of Land Appeals by the Secretary of the Interior, 43 CFR 4.1, the decision of the Director, Minerals Management Service, is affirmed.

C. Randall Grant, Jr.
Administrative Judge

I concur:

John H. Kelly
Administrative Judge

10/ In upholding the Federal marketable condition rule "that marketing costs cannot be deducted from the gross proceeds, equal to the value of production, before royalty is calculated," the court expressly declined a request from Mesa to "import commonly understood meanings of lease terms from cases decided in the state courts of this Circuit." 931 F.2d at 325 n.48 (emphasis in original).